ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

APPLICATION OF DUKE ENERGY INDIANA, LLC FOR APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR ELECTRIC SERVICE, FOR APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR HIGH PRESSURE STEAM SERVICE, AND TO UPDATE MONTHLY BENCHMARKS FOR CALCULATION OF PURCHASED POWER COSTS IN ACCORDANCE WITH INDIANA CODE § 8-1-2-42, INDIANA CODE § 8-1-2-42.3 AND VARIOUS ORDERS OF THE INDIANA UTILITY REGULATORY COMMISSION)))))))))))

CAUSE NO. 38707 FAC 109

APPROVED: SEP 28 2016

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
David E. Veleta, Senior Administrative Law Judge

On July 27, 2016, Duke Energy Indiana, LLC ("Applicant") filed its Verified Application and direct testimony and exhibits for approval by the Indiana Utility Regulatory Commission ("Commission") of a change in its fuel adjustment charge ("FAC") to be applicable during the billing cycles of October, November, and December 2016 for electric and steam service and to update monthly benchmarks for purchased power costs. On July 27, 2016, Applicant filed a Motion for Protection of Confidential and Proprietary Information ("Motion"). On July 28, 2016, the Duke Energy Indiana Industrial Group ("Industrial Group") filed its Petition to Intervene in this proceeding. On August 2, 2016, Steel Dynamics, Inc. ("SDI") filed its Petition to Intervene in this proceeding. On August 9, 2016, the Presiding Officers granted Applicant's Motion. The Presiding Officers granted the Petitions to Intervene of SDI and the Industrial Group on August 9, 2016. The Indiana Office of Utility Consumer Counselor ("OUCC") filed its audit report and testimony on August 31, 2016. On September 13, 2016, the Presiding Officers issued a Docket Entry requesting additional information from Applicant. On September 16, 2016, Applicant filed its response to the Presiding Officers' Docket Entry.

A public evidentiary hearing was held in this Cause on September 20, 2016, at 9:30 a.m., in Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Applicant, the Industrial Group, and the OUCC appeared at the hearing by counsel. Applicant and the OUCC offered their respective prefiled testimony and exhibits into the evidentiary record without objection. No members of the general public appeared or sought to testify at the hearing.

Based upon the applicable law and the evidence, the Commission now finds:

1. **Notice and Commission Jurisdiction.** Notice of the hearing in this Cause was given as required by law. Applicant is a public utility within the meaning of Ind. Code § 8-1-2-1(a). Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes to Applicant's rates and charges

related to adjustments in fuel costs. Therefore, the Commission has jurisdiction over the parties and the subject matter of this Cause.

2. **Applicant's Characteristics.** Applicant is a public utility corporation organized and existing under the laws of the State of Indiana with its principal office in Plainfield, Indiana, and is a second tier wholly-owned subsidiary of Duke Energy Corporation. Applicant is engaged in rendering electric utility service in the State of Indiana and owns, operates, manages, and controls, among other things, plant and equipment within the State of Indiana used for the production, transmission, delivery and furnishing of such service to the public. Applicant also renders steam service to one customer, International Paper.[1]

3. **Available Data on Actual Fuel Costs and Authorized Jurisdictional Net Income.** On May 18, 2004, the Commission issued an Order in Cause No. 42359 ("May 18 Order") approving base retail electric rates and charges for Applicant. The Commission's May 18 Order found that Applicant's base cost of fuel should be 14.484 mills per kWh and that Applicant's base rates for electric utility service should reflect an authorized jurisdictional net operating income of $267,500,000, prior to any additional return on qualified pollution control property approved by the Commission, pursuant to Ind. Code §§ 8-1-2-6.6 and 6.8, not taken into account in the May 18 Order.

Applicant's cost of fuel to generate electricity and the cost of fuel included in the net cost of purchased electricity for the month of May 2016, based on the latest data known to Applicant at the time of filing after excluding prior period costs, hedging, and miscellaneous fuel adjustments, if applicable, was $0.024959 per kWh as shown on Applicant's Exhibit A, Schedule 9. In accordance with previous Commission Orders,[2] Applicant calculated its phased-in authorized jurisdictional net operating income level for the 12-month period ending May 31, 2016, to be $498,710,000. No evidence was offered objecting to the calculation of the authorized jurisdictional net operating income level proposed by Applicant, and we find it to be proper.

4. **Fuel Purchases.** Mr. Brett Phipps testified regarding Applicant's coal procurement practices and its coal inventories. Mr. Phipps testified that as of May 31, 2016, coal inventories were approximately 3,764,706 tons (or 69 days of coal supply), which is lower than what was reported in FAC108 due to a number of factors, including drawing down the inventory at Wabash River in planned amounts in preparation for the retirement of units 2 through 5 on April 15, 2016, and suspension of the operation of unit 6 on that same date, and a reduction of inventory due to the utilization of the coal price decrement. Mr. Phipps added that Applicant continues to evaluate a host of options in order to effectively manage its coal inventory. Mr. Phipps stated that as inventory levels dictate, Applicant explores options to store or defer contract coal or resell surplus coal into the market. Due to continued

[1] International Paper acquired Temple-Inland's corrugated packaging business on February 13, 2013.

[2] The Commission's July 3, 2002, Order in Cause Nos. 41744 S1 and 42061, and subsequent update Orders, up to and including the January 27, 2016, update in Cause No. 42061 ECR 26, authorized Applicant to add the value of certain qualified pollution control property to the value of Applicant's property for ratemaking purposes. The Commission's Order in Cause No. 42061 ECR 3, dated March 11, 2004, stated that the applicable incremental increase to Applicant's authorized return, approved in that proceeding, shall be phased-in over the period of time that Applicant's net operating income was affected by the applicable construction work in progress ("CWIP") update. The Commission's Order in Cause No. 43114 and subsequent update Orders, up to and including the September 11, 2013 update in Cause No. 43114 IGCC 10, authorized Applicant to add the value of property at the Edwardsport Integrated Gasification Combined Cycle Generating Facility ("IGCC Project") to the value of Applicant's property for ratemaking purposes. Applicant has applied the same phase-in concepts ordered by the Commission in its Order in Cause No. 42061 ECR 3 for CWIP updates to the IGCC Project updates in making the calculations for this filing.

weak coal market conditions, resale opportunities will continue to be extremely difficult in the near term. Mr. Phipps testified that it was his opinion that Applicant is purchasing coal and oil at prices as low as reasonably possible.

Mr. Phipps testified that spot natural gas prices are dynamic, volatile, and can change significantly day to day based on market fundamental drivers. During the three-month period from March through May 2016 the price Applicant paid for delivered natural gas at its gas burning stations was between \$1.44 per million BTU and \$2.90 per million BTU. Mr. Phipps testified that, in his opinion, Applicant purchased natural gas at the lowest cost reasonably possible.

The OUCC's witness Mr. Michael Eckert testified regarding Applicant's coal inventory. He testified that Applicant has met with its suppliers, determined maximum storage at its facilities, is exploring options to resell surplus coal, and applied decrement coal pricing. He recommended Applicant should continue to update the Commission on its coal inventory and its use of decrement pricing.

Applicant's witness Mr. John D. Swez testified regarding Applicant's efforts to mitigate the negative Locational Marginal Price ("LMP") situation associated with power purchased from Benton County Wind Farm ("BCWF"), pursuant to the contract which was approved by the Commission in Cause No. 43097. Mr. Swez stated that due to the nature of the contractual agreement between the Company and BCWF and the way the Midcontinent Independent System Operator, Inc. ("MISO") treats offers from intermittent resources, the unit had a commitment status of must run with minimum and maximum loading equal to the forecasted generation amount, meaning that MISO would clear the generator at any LMP at the forecasted amount in the day-ahead market. Mr. Swez testified that because of this, negative revenue (meaning that payments must be made to send the power into the MISO system) was sometimes received by this generator in the day-ahead markets. It was also possible to receive negative revenues in the real-time market. Mr. Swez testified that on March 1, 2013, BCWF began operation as a Dispatchable Intermittent Resource ("DIR"). The DIR construct was designed to allow MISO to better manage the output of intermittent resources, thereby allowing for better management of congestion in certain areas, such as where BCWF is located. Mr. Swez testified that although it appears that the DIR construct is giving MISO additional tools to manage congestion at BCWF, negative LMPs at times do continue to be observed.

Mr. Swez also testified that Applicant received an invoice on June 17, 2013 for payment from BCWF for March, April, and May 2013 for liquidated damages for production that was not generated. He noted that Applicant disputed this invoice and, as a result, did not issue payment or include the invoice in any FAC proceeding. Although Applicant and BCWF had continued negotiations regarding this invoice, BCWF filed a lawsuit against Applicant on December 16, 2013, alleging that Applicant breached its contract with the wind farm. A trial was scheduled for August 2015; however, in early July the court entered summary judgment on behalf of Applicant in the case, meaning that Applicant's supply offer was found to be reasonable. Further, because the court entered judgment in the Applicant's favor on all remaining claims, no payment is owed to BCWF for power not actually generated and delivered. Mr. Swez testified that on July 30, 2015 BCWF filed a notice of appeal. Although both parties participated in a court-ordered settlement conference, no settlement was reached. The appeal was fully briefed and oral argument was heard in the 7th Circuit Court on February 26, 2016. No decision has been issued at this time.

Mr. Eckert recommended that Applicant report to the Commission any updates and resolutions to the BCWF situation in its next FAC filing.

Mr. Swez testified that during March 2016, the Edwardsport IGCC Generating Station produced the fifth most generation in any month since being declared commercial. During periods of April and May 2016, the station underwent its spring maintenance outage. During June, the station rebounded with the fourth most generation in any month. He testified that when the unit's gasifiers are available or operating, Edwardsport IGCC is being offered with a commitment status of must-run. Mr. Swez stated that Edwardsport IGCC has followed MISO's dispatch direction between the minimum and maximum capability of the unit during this time. Mr. Swez also testified that during times when syngas is not available and the station is available on natural gas operation, the unit will typically be offered to MISO with a commitment status of economic and can be committed and dispatched at MISO's discretion.

Based on the evidence presented, we find that Applicant made every reasonable effort to acquire fuel for its own generation or to purchase power so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible. With regard to its coal inventory levels and any updates to the situation with BCWF, Applicant will provide an update on the status in its next FAC proceeding as recommended by the OUCC.

5. **<u>Hedging Activities</u>.** Applicant's witness Mr. Wenbin (Michael) Chen testified the Company takes advantage of the hedging tools available to protect against natural gas price fluctuations. Mr. Chen testified that since the last update to the Commission in the FAC108 proceeding, the Company purchased some forward natural gas hedges for expected native gas burn in July and August 2016. He testified that there were no realized gas hedging results for this period because all hedging positions were still open forward positions, however a $2,299 transaction fee was incurred in May 2016 associated with buying the forward hedges. He further testified Applicant experienced net realized power hedging losses (exclusive of MISO virtual trades and including prior period adjustments) for the period of $123,659. In total, the Company realized a total net loss of approximately $125,958 during the period for all native gas and power hedging activities.

Mr. Chen explained that, consistent with the Commission's June 25, 2008 Order in Cause No. 38707 FAC 68 S1 ("FAC 68 S1 Order"), beginning on August 1, 2008, Applicant has not utilized its flat hedging methodology. Rather, Applicant will hedge up to approximately flat minus 150 MW on a forward, monthly and intra-month basis, and up to approximately flat on a Day Ahead/Real-Time basis. This methodology will leave the Company with at least 150 MW of expected load unhedged on a forward forecasted basis. Mr. Chen opined Applicant's gas and power hedging practices are reasonable. He stated Applicant never speculates on future prices, and that its hedging practice is economic at the time the decision is made and reduces volatility because Applicant is transacting in a less volatile forward market, as opposed to more volatile spot markets. Mr. Chen testified that, as mentioned in the FAC100 proceeding, Applicant restarted using virtual trades as a hedging tool for expected forced outages in the Real-Time market because of heightened LMP price volatility caused by gas supply issues and extremely cold weather experienced in the past winter. Mr. Chen testified that Applicant most recently met with the OUCC in July 2014 to discuss Applicant's hedging strategy.

No evidence was offered in this Cause noting issues with the realized net amounts for power and gas hedging included in the fuel costs in this proceeding or challenging the prudence of the activities that gave rise to the realized net amounts. In addition, Applicant presented evidence that its power hedging practices relevant to this proceeding were consistent with the Agreement previously approved in the FAC 68 S1 Order. Thus, we allow Applicant to include $125,958 of net losses from native gas and power hedges in the calculation of fuel costs in this proceeding.

6. **Energy and Ancillary Services Markets ("ASM").** On June 1, 2005, the Commission issued an Order in Cause No. 42685 ("June 1 Order"), in which we approved certain changes in the operations of the investor-owned Indiana electric public utilities that are participating members of MISO. In this proceeding, Mr. Swez testified that Applicant included Energy Markets charges and credits incurred as a cost of reliably meeting the power needs of Applicant's load, including: (1) Energy Markets charges and credits associated with Applicant's own generation and bilateral purchases that were used to serve retail load; (2) purchases from MISO at the full LMP at Applicant's load zone; (3) other Energy Markets charges and credits included in the list on page 37 of the June 1 Order; and (4) credits and charges related to auction revenue rights ("ARRs") and Schedule 27 and Schedule 27-A.

Applicant's witness Ms. Mary Ann Amburgey testified as to the procedures followed by Applicant to verify the accuracy of the charges and credits allocated by MISO to Applicant. She also discussed the process by which MISO issues multiple settlement statements for each trading day and the dispute resolution process with respect to such statements. She stated that every daily settlement statement received by Applicant from MISO is reviewed utilizing the computer software tools described in her testimony. Ms. Amburgey testified that she is confident that the amounts paid by Applicant to MISO, net of any credits, are proper and that such amounts billed to customers through the FAC are proper. She testified that there are two new MISO charge types that may impact the fuel adjustment factor in this proceeding – the Day Ahead and Real Time Ramp Capability, which started on May 1, 2016. Mr. Swez testified that Applicant proposes to include these new charge types, as well as the corresponding cost component for these new charge types from the Real-Time Revenue Neutrality Uplift Amount, the Ramp Capability Distribution Uplift Amount, in the Fuel Adjustment Clause. In response to the Commission's docket entry, Mr. Swez clarified that the amount of recovery requested in this FAC for the Ramp Capabaility Distribution Uplift is zero, but that there may be costs sought to be recovered in future filings. The response to the docket entry also clarified that credits were included in this filing as Duke Energy Indiana generating units cleared/ and or were deployed as ramp capability in both the Day-Ahead and Real-Time markets. Applicant's Exhibit A Schedule 11 lines 54 and 55 indicate the credited amount was $1,606.88.

In its Phase II Order in Cause No. 43426 ("Phase II Order") the Commission authorized Applicant and the other Joint Petitioners to recover costs and credit revenues related to the Ancillary Services Market ("ASM"). Mr. Swez explained that Applicant has included various ASM charges and credits in this proceeding incurred for March through May 2016, consistent with the Phase II Order, as well as appropriate period adjustments.

Applicant's witness Mr. Scott A. Burnside testified that Applicant, in accordance with the Phase II Order, has calculated the monthly average ASM Cost Distribution Amounts it has paid for Regulation, Spinning and Supplemental Reserves. These amounts are as follows:

(in $ per MWh)	Mar-16	Apr-16	May-16
Regulation Cost Dist.	0.0389	0.0412	0.0439
Spinning Cost Dist.	0.0338	0.0333	0.0383
Supplemental Cost Dist.	0.0102	0.0107	0.0127

OUCC witness Mr. Eckert testified that Applicant's treatment of ASM charges follows the treatment ordered by the Commission in its Phase II Order.

Based upon the evidence presented, the Commission finds that Applicant's treatment of the Energy and ASM charges and credits in its cost of fuel is consistent with the June 1 Order, the December 28, 2006 Order in Cause No. 38707 FAC 70, as well as our Phase I and Phase II Orders in Cause No. 43426 and should be approved.

7. **Participation in the Energy and ASM Markets and MISO-Directed Dispatch.** As previously noted, the June 1 Order approved certain changes in the operations of Applicant as a result of the implementation of the Energy Markets. Specifically, we found that Applicant (and the other electric utilities participating in Cause No. 42685) should be granted authority to participate in the MISO Day 2 directed dispatch and Day 2 energy markets as described in their testimony. Mr. Swez generally described Applicant's participation in the MISO energy markets and testified that it was consistent with the testimony presented in Cause No. 42685. Mr. Swez discussed in his filed testimony the offer process and noted there are a variety of reasons that Applicant will either offer a generating resource as must-run or self-schedule a unit to ensure the unit is operated as cost efficiently as possible.

Mr. Swez testified that beginning in late February 2012, a coal price decrement was applied to the dispatch costs of Gibson Units 1-5, Wabash River Units 2-6, and Cayuga Units 1-2 to correctly reflect the economics of additional costs associated with avoiding or reducing surplus coal inventories. He stated that, to the extent that the price decrement results in units being dispatched that otherwise would not be, coal coming to the station is consumed, other potential costs are avoided, and customers ultimately benefit because higher cost alternatives to manage the inventory are avoided. Mr. Swez testified the price decrement is working as designed as Applicant initially saw a significant increase in generation output from these units. As the level of the coal price decrement has decreased over time, the impact of the decrement has lessened. Mr. Swez testified that on July 28, 2015, a non-zero coal price decrement was initiated for Cayuga 1-2 and Gibson 1-5. In addition, on November 11, 2015, the coal price decrement was initiated for Wabash River 6. In the October 30, 2013 Order in Cause No. 38707 FAC 96, the Commission ordered Applicant to present the inputs to its calculation of the coal price decrement applicable to each FAC filing as support for the reasonableness of its pricing. Mr. Swez provided the confidential coal stacks for the time period March through May 2016. Mr. Swez testified that Applicant continues to forecast its coal inventory position as part of the normal course of business.

Mr. Swez testified that Wabash River units 2-5 were retired on April 15, 2016. These units were previously granted a one-year extension of the April 2015 Mercury and Air Toxics Standards ("MATS") rule compliance date due to the need for at least two of the four units to operate at any given time for transmission system reliability. He explained that in consideration of the minimization of MATS related emissions during the extension period and the operational complexities of units at this point in the lifecycle, Applicant employed a MISO offer strategy that prioritized availability and operation of the units to solve transmission reliability constraints. As a result, Applicant generally held two of the four of Wabash River units 2-5 in reserve shutdown available for emergency operation only. He testified that the number of units in reserve versus operation varied depending on unit availability, the needs of the transmission system, and energy prices in the MISO market. Mr. Swez testified that Applicant's goal was to maintain the availability of the generating units primarily for transmission reliability support, and specifically to maintain availability during peak demand times such as summer and winter periods when transmission related events and/or energy prices had the highest customer impact. Wabash River Unit 6 also had a one-year MATS rule extension until April 15, 2016. Applicant considered but has decided not to convert the unit to natural gas fuel. On June 7, 2016, it submitted a request to MISO for a unit decommissioning and retirement date of December 7, 2016. MISO is studying the request and has not yet provided the conclusion to date.

Based upon the evidence presented we find Applicant's participation in the energy and ancillary services markets constituted reasonable efforts to generate or purchase power, or both, to serve its retail customers at the lowest fuel cost reasonably possible. Further, as we noted in our Orders in Cause Nos. 38707 FAC 81 and 38707 FAC 82, should Applicant's bidding strategy alter the native/non-native load assignment of its units, such strategy may be subject to further prudence review.

8. Major Forced Outages. In the December 28, 2011 Order in Cause No. 38707 FAC90, the Commission ordered Applicant to discuss in future FAC proceedings major forced outages of units of 100 MW or more lasting more than 100 hours. Mr. Swez testified that there was one outage during this FAC period that met these criteria. He stated that an outage occurred at Wabash River 6 from April 6 through April 15 associated with the shutdown of the unit as required prior to April 15, 2016.

9. Operating Expenses. Ind. Code § 8-1-2-42(d) (2) requires the Commission to determine whether actual increases in fuel costs have been offset by actual decreases in other operating expenses. Accordingly, Applicant filed operating cost data for the 12 months ended May 31, 2016. Applicant's authorized phased-in jurisdictional operating expenses (excluding fuel costs) are $865,371,000. For the 12-month period ended May 31, 2016, Applicant's jurisdictional operating expenses (excluding fuel costs) totaled $1,190,874,000. Accordingly, Applicant's actual operating expenses exceeded jurisdictional authorized levels during the period at issue in this Cause. Therefore, the Commission finds that Applicant's actual increases in fuel costs for the above referenced periods have not been offset by decreases in other jurisdictional operating expenses.

10. Return Earned. Ind. Code § 8-1-2-42(d)(3), subject to the provisions of Ind. Code § 8-1-2-42.3, generally prohibits a fuel cost adjustment charge that would result in regulated utilities earning a return in excess of its applicable authorized return. Should the fuel cost adjustment factor result in the utility earning a return in excess of its applicable authorized return, it must, in accordance with the provisions of Ind. Code § 8-1-2-42.3, determine if the sum of the differentials between actual earned returns and authorized returns for each of the 12-month periods considered during the relevant period is greater than zero. If so, a reduction to the fuel adjustment clause factor is deemed appropriate.

In accordance with previous Commission Orders, Applicant's calculated jurisdictional electric operating income level was $443,142,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Ind. Code § 8-1-2-42(d)(3), was $498,710,000. Therefore, the Commission finds that Applicant did not earn a return in excess of its authorized level during the 12 months ended May 31, 2016.

11. Estimation of Fuel Costs. Applicant estimates that its prospective average fuel cost for the months of October through December 2016 will be $69,246,667 or $0.025914 per kWh. Applicant previously made the following estimates of its fuel costs for the period March through May 2016, and experienced the following actual costs, resulting in percent deviation, as follows:

Month	Actual Cost in Mills/kWh	Estimated Cost in Mills/kWh	Percent Actual is Over (Under) Estimate
March 2016	21.105	25.822	(18.27)
April 2016	26.083	25.986	0.37
May 2016	25.042	26.204	(4.43)
Weighted Average	24.045	26.001	(7.52)

A comparison of Applicant's actual fuel costs with the respective estimated costs for these three periods results in a weighted average percentage difference of (7.52). Based on the evidence of record, we find Applicant's estimating techniques appear reasonably sound and its estimates for October through December 2016 should be accepted.

12. Purchased Power Benchmark. Applicant has calculated monthly purchased power benchmarks in accordance with the Commission's August 18, 1999 Order in Cause No. 41363 and the guidance of this Commission in Cause Nos. 38706 FAC 45, 38708 FAC 45, 38707 FAC 56, and 38707 FAC 59. The benchmarks are as follows:

Month / Year	Benchmark $/MWh	Facility
March 2016	27.71	Vermillion 2
April 2016	32.49	Vermillion 3
May 2016	159.23	Connersville 1

Mr. Burnside testified that based on a comparison of the weighted average purchase power costs for each calendar week of the month compared to the monthly benchmark prices, Applicant exceeded the benchmark in April 2016. Applicant did not exceed benchmarks in March or May 2016. Mr. Burnside testified that during the week of April 10 through 16, 8,297 MWh of power was purchased at a weighted average cost of $38.24. During the week of April 17 through 23, 10,379 MWh of power was purchased at a weighted average cost of $33.24. Lastly, during the week of April 24 through 30, 38,370 MWh of power was purchased at a weighted average cost of $35.68. Mr. Burnside testified that the cost of purchased power during these three weeks exceeded the benchmark of $32.49 by a total of $177,835. Mr. Burnside testified that Applicant followed MISO's economic dispatch and unit commitment instructions. Mr. Burnside explained Applicant's decision not to self-commit peaking units during hours when the cost of purchased power was greater than the benchmark. He compared the approximate hourly cost of purchased power with the hypothetical cost of self-committing peaking units, which demonstrated that the occasional purchase of power at a cost exceeding the benchmark was less than the alternative of starting additional generating units. Mr. Burnside also testified that in April, when prices are typically low, many units were performing scheduled spring maintenance. The benchmark price itself was also unusually low due to low natural gas fuel prices. Most of the higher priced hours followed an event, such as the loss of a unit somewhere in the MISO footprint. The market responded with high prices that returned to normal within a few hours.

Mr. Burnside testified that Applicant is seeking to recover $177,835 of purchased power cost in excess of the April 2016 benchmark. He testified that the benchmark purchases in the month of April were prudent and reasonable under the circumstances known at the time.

The OUCC's witness Mr. Michael Eckert testified that Applicant did not purchase any power that was non-recoverable.

Based on the evidence of record, the Commission finds that Applicant has met the requirements necessary to establish monthly benchmarks for power purchases that occurred during the March through May 2016 reconciliation period. The Commission further finds that Applicant's request for recovery of its purchased power over the benchmark for April 2016 is consistent with the Commission's Purchased Power Order and should be approved.

13. Fuel Cost Factor. As discussed in Finding No. 3 above, Applicant's base cost of fuel is 14.484 mills per kWh. The evidence indicates that Applicant's fuel cost adjustment factor applicable to October through December 2016 billing cycles is computed as follows:

	$ / kWh
Projected Average Fuel Cost	0.025914
Net Variance	(0.002086)
Adjusted Fuel Cost Factor	0.023828
Less: Base Cost of Fuel	0.014484
Fuel Cost Adjustment Before Applicable Taxes	0.009344
Adjustment for Utility Receipts Tax	0.000141
Fuel Cost Adjustment Factor Adjusted for Applicable Taxes	0.009485

The net variance factor shown above reflects $14,006,333 of over-billed fuel costs applicable to retail customers that occurred during the period March through May 2016.

OUCC witness Mr. Gregory Guerrettaz testified that the fuel cost adjustment for the quarter ended May 2016 had been properly applied by Applicant. In addition, he stated the figures used in the Application for a change in the FAC were supported by Applicant's books and records, Sumatra, and source documentation of Applicant for the period reviewed.

14. Effect on Residential Customers. The approved factor represents a decrease of $0.001727 per kWh from the factor approved in Cause No. 38707-FAC108. The typical residential customer using 1,000 kWhs per month will experience a decrease of $1.72 or 2.0% on his or her electric bill compared to the factor approved in Cause No. 38707 FAC 108 (excluding various tracking mechanisms and sales tax).

15. Interim Rates. Because we are unable to determine whether Applicant's actual earned return will exceed the level authorized by the Commission during the period that this fuel cost adjustment factor is in effect, the Commission finds that the rates approved should be approved on an interim basis in the event an excess return is earned.

16. Fuel Adjustment for Steam Service. On December 30, 1992, this Commission issued its Order in Cause No. 39483 approving the June 18, 1992 Settlement Agreement between Applicant and Premier Boxboard, formerly referred to as Temple-Inland, n/k/a International Paper which included a change in the method used to calculate International Paper's fuel cost adjustment as well as an update to the base cost of fuel. The fuel cost adjustment factor for International Paper of $1.1249685 per 1,000 pounds of steam was calculated on Exhibit B, Schedule 1, of the Verified Application; this factor will be effective for the October through December 2016 billing cycles. Exhibit B, Schedule 2, of the Verified Application is a reconciliation of the actual fuel cost incurred to estimated fuel cost billed to International Paper that resulted in $117,101 payable to International Paper for the months of March through May 2016.

The Commission finds that Applicant's proposed fuel cost adjustment factor for International Paper of $1.1249685 per 1,000 pounds of steam has been calculated in accordance with this Commission's Order in Cause No. 39483, and that such factor should be approved. We further find that Applicant's reconciliation amount of $117,101 payable to International Paper has been properly determined and should be approved.

17. **Shared Return Revenue Credit Adjustment for International Paper.** In accordance with the June 18, 1992 Settlement Agreement, International Paper will receive shared return revenue credit adjustments to the extent incurred. As indicated above in Finding No. 10, Applicant did not have excess earnings for the 12 months ended May 2016. Therefore, we find International Paper is not due a shared return revenue credit.

18. **Confidential Information.** On July 27, 2016, Applicant filed its motion seeking a determination that designated confidential information involved in this proceeding be exempt from public disclosure under Ind. Code § 8-1-2-29 and Ind. Code ch. 5-14-3. The request was supported by the affidavits of John D. Swez and Scott A. Burnside, showing documents offered into evidence at the evidentiary hearing were trade secret information within the scope of Ind. Code § 5-14-3-4(a)(4) and Ind. Code § 24-2-3-2. On August 9, 2016, the Presiding Officers issued a docket entry finding such information confidential on a preliminary basis. After reviewing the designated confidential information, we find all such information qualifies as confidential trade secret information pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2. This information has independent economic value from not being generally known or readily ascertainable by proper means. Applicant takes reasonable steps to maintain the secrecy of the information and disclosure of such information would cause harm to Applicant. Therefore, we affirm the preliminary ruling and find this information should be exempted from the public access requirements contained in Ind. Code ch. 5-14-3 and Ind. Code § 8-1-2-29, and held confidential and protected from public disclosure by this Commission.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. Duke Energy Indiana's fuel cost adjustment factor for electric service to be billed jurisdictional customers, as set forth in Finding No. 13, and the fuel cost adjustment for steam service as set forth in Finding No. 16 of this Order are hereby approved on an interim basis, subject to refund, in accordance with all of the Findings above.

2. Duke Energy Indiana's inclusion of Energy and Ancillary Services Markets charges and credits in its cost of fuel, as described in Finding No. 6 of this Order, is hereby approved.

3. Prior to implementing the authorized rates, Applicant shall file Rider 60 under this Cause for approval by the Commission's Energy Division. Rider 60 shall be effective for all bills rendered on and after the first billing cycle of October 2016.

4. Duke Energy Indiana shall provide an update on the status of its coal inventories and the situation with Benton County Wind Farm in its next FAC filing, as described in Finding No. 4 of this Order.

5. The material submitted to the Commission under seal shall be and hereby is declared to contain trade secret information as defined in Ind. Code § 24-2-3-2 and therefore is exempted from the public access requirements contained in Ind. Code ch. 5-14-3 and Ind. Code § 8-1-2-29.

6. This Order shall be effective on and after the date of its approval.

FREEMAN, HUSTON, WEBER, AND ZIEGNER CONCUR; STEPHAN ABSENT:

APPROVED: SEP 28 2016

I hereby certify that the above is a true and correct copy of the Order as approved.

Mary M Becerra

Mary Becerra
Secretary of the Commission